

High-Octane Gasoline from Biomass: Experimental, Economic, and Environmental Assessment



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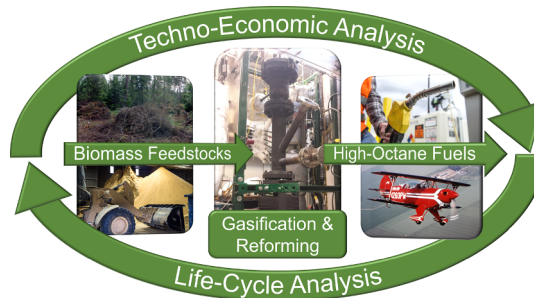
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HIGHLIGHTS

- Syngas compositions, heating values, and yields were independent of feedstock.
- Syngas from blended feedstocks follows a linear mix of the constituent feeds.
- Miscanthus is the most cost-effective feedstock to produce high-octane fuels.
- Forest residues has the lowest associated life-cycle carbon emissions.

GRAPHICAL ABSTRACT



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ABSTRACT

Five economically-advantaged biomass feedstocks identified in the United States Department of Energy's 2016 Billion Ton Study were gasified and the syngas was reformed at the bench scale to study the feedstock price-performance relationship. The distribution of reformed syngas compositions, heating values, and yields were similar across the different feedstocks and blends thereof, which ranged from inexpensive residual wastes to more expensive and higher quality biomass, revealing that feedstock performance was mostly insensitive to its price. Custom blended feedstocks produced syngas with characteristics resembling linear combinations of syngas from single-component feedstocks, supporting the ability to customize and predict blended properties based on single-feedstock data. The experimental gasification data informed a techno-economic analysis of specific feedstock costs for producing high-octane gasoline, and the results showed that miscanthus and forest residues were the most cost-effective. A field-to-wheels life-cycle assessment of greenhouse gas emissions showed that forest residues was the most environmentally benign feedstock of those studied.

1. Introduction

The thermochemical conversion (i.e., gasification) of renewable biomass to synthesis gas (syngas) represents an alternative pathway to

produce many traditionally fossil-based fuels and chemicals. Syngas can be catalytically upgraded through one of several commercially established “gas-to-liquids” (GTL) pathways including Fischer-Tropsch (FT) synthesis, methanol synthesis, methanol derivatives such as methanol-

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to-gasoline (MTG), methanol-to-olefins (MTO), and Mobil's olefins to gasoline and distillates (MOGD) [1,2]. Additionally, the conversion of syngas-derived dimethyl ether over large-pore zeolites has recently been proposed as a promising route to high-octane gasoline (HOG) [3,4].

Through leveraging the operational flexibility afforded by gasification, syngas can be produced from essentially any source of biomass or carbonaceous feedstock as illustrated by the hundreds of species studied in literature [5–8]. However, in moving from lab-scale to commercial-scale processes, the number of viable feedstock options is significantly more limited due to practical issues including high-volume availability, price, performance, and logistical dependencies between the feedstocks [9]. For example, the United States Department of Energy (DOE) has defined a “high-impact feedstock” as a “feedstock that is domestically available and has the agronomically and ecologically sustainable ultimate availability potential of at least 50 million dry metric tons of cellulosic biomass per year” [10]. The strategic plan of the DOE to develop renewable fuels is based almost entirely on such feedstocks [11] because integrated biorefineries will require high volumes of these in order to take advantage of economies of scale to reduce the cost of renewable fuel production. As biomass feedstocks eventually become commoditized, biorefineries will likely have strong incentives to combine multiple disparate feedstocks in order to reduce the demand and cost for individual feedstocks [12,13]. Additional benefits to feedstock blending are reduced risks due to excessive dependence upon a single resource, reduced shipping costs, and reduced storage costs through sourcing materials that can be harvested at different times throughout the year. Moreover, the availabilities of some feedstocks are inter-dependent. For example, forest residues are generally a low-cost feedstock, but their availability depends on harvesting and use of whole trees, usually either for pulp and paper, saw logs or wood pellets. The total projected domestic availability of logging residues is considered below 45 million metric tons until at least 2040 [14]. Because of the relatively low availability of forest residues, it is likely that individual large-scale biorefineries that utilize forest residues will also need to source whole trees, milling residues, energy crops, or construction and demolition wastes, in order to achieve their designed throughputs [13,14].

Practical implementation of feedstock flexibility, however, requires an understanding of how differences in the physical and chemical properties of feedstocks (e.g., H, C, O, and ash content) affect syngas composition and system operation (e.g., upstream and downstream processing), and an understanding of the behavior of blended feedstocks. The work detailed herein describes a first-of-a-kind study combining experimental results from a uniquely integrated and commercially relevant gasifier system with rigorous techno-economic analysis and life-cycle assessment to evaluate key US feedstocks for the potential to produce high-octane gasoline from biomass-derived syngas. This study evaluated five biomass feedstocks outlined by the Billion Ton Study [14], comprising clean loblolly pine, hybrid poplar, miscanthus, switchgrass, forest residues and two custom blends in a 4-inch (10.16 cm) diameter bench-scale, integrated gasifier system. The objective was to provide information on feedstock synergies and the degree to which the blended syngas properties may be predicted from the individual feedstock syngas data, allowing gasification plants to potentially interchange feedstocks or blends without process upsets or significant effects to syngas production cost, quality, or yield.

Finally, techno-economic analysis (TEA) and supply chain life-cycle assessment (LCA) based on the experimental data were also performed. TEA results can be used by policymakers and researchers to help refine research objectives and associated performance targets that will be necessary to commercially produce cost-competitive fuels from biomass. The objective of the present TEA study was to shed light on the ramifications to process economics resulting from different feedstock costs and compositions (e.g., ash content). Additionally, the success of the biofuels industry depends not only on economic viability, but also

on environmental sustainability. LCA is a tool to quantify and assess the environmental impacts associated with the production and consumption of a product. The extent of greenhouse gas (GHG) emissions associated with the life cycle of HOG, from biomass feedstock production to the end of life (i.e., fuel combustion) and those attributed to the selected feedstocks were quantified and assessed. Thus, TEA coupled with LCA can play a key role in process developers understanding the technical, economic, and environmental barriers and tradeoffs for HOG production from the evaluated feedstocks. Ultimately, through these experimental and combined TEA and LCA efforts, the results highlight the most important considerations with respect to feedstock selection for large-scale gasification and the effect of blending feedstocks.

2. Materials and methods

2.1. Feedstock preparation

Clean loblolly pine (CP), hybrid poplar (HP), miscanthus (MI), switchgrass (SG), and forest residues (FR) were chosen for this study based on their relatively high abundance and low cost as outlined in the 2016 Billion Ton Study [14]. The clean loblolly pine (*Pinus taeda*) was debarked and de-limbed whole tree and was harvested from Edgefield County, SC. The hybrid poplar (*P. deltoides* × *P. nigra*) was harvested from Morrow County, OR, the miscanthus (*Miscanthus* × *giganteus*) was harvested from Tift County, GA, and the switchgrass (*Panicum virgatum*) was harvested from Texas County, OK. Forest residues are generally defined as the remaining material from conventional forest operations consisting of tops, branches, needles, bark, and unmerchantable wood [15]. This particular lot of FR (*Pinus taeda* with a small amount of *Pinus virginiana* included) was harvested from Halifax County, VA. Each biomass feedstock was dried to approximately 10% moisture and then processed in a Schutte-Buffalo hammer mill (Circ-U-Flow model 18-7-300) using 6.35 mm and 2.0 mm screens consecutively, resulting in a particle size distribution of 518–653 μm (mean) and 567–695 μm (vol. wt. mean). Blended feedstocks were prepared on a dry mass basis by physically mixing the milled base feedstocks; the blends were 50% FR and 50% SG (hereafter 50/50 blend) and 60% FR, 30% CP, and 10% HP (hereafter 60/30/10 blend). SG and FR were chosen for the 50/50 blend because initial results indicated that the two feedstocks were the most dissimilar with respect to observed syngas composition, thereby affording the opportunity to study possible blend linearity. The 60/30/10 blend was chosen based on industrial relevance as an economically-viable model feedstock in which multiple components will likely be required in many areas to achieve the feedstock volume needed by a full-scale biorefinery within an economical draw radius. Sourcing large amounts of forest residues will likely also require sourcing whole trees across varied forests, especially natural forests, which are not pure but include a mixture of other species, including hardwoods. For the 60/30/10 blend, hybrid poplar is included to represent potential mixed hardwoods that could be harvested with the target pine resource.

2.2. Feedstock analytical characterization

The feedstock samples were prepared for analytical characterization with an Ultra Centrifugal Mill ZM 200 using a 200 μm screen at 8000 RPM (Retsch GmbH). A thermogravimetric method using ASTM D7582-15 was used for proximate analysis. For moisture content, the LECO TGA 701 was heated to 107 °C and held until a constant mass was reached under a nitrogen flow of 10 standard liters per minute (slm). The crucibles were capped with ceramic covers, and the temperature was then ramped to 950 °C and held for 7 min to determine volatiles content. Ash content was determined by cooling the instrument to 600 °C, removing the covers, and switching the gas to a flow of 3.5 slm of oxygen. The temperature was then increased to 750 °C and held until a constant mass was reached. Fixed carbon was calculated from the weight loss during the ashing step. Ultimate analysis of the feedstocks,

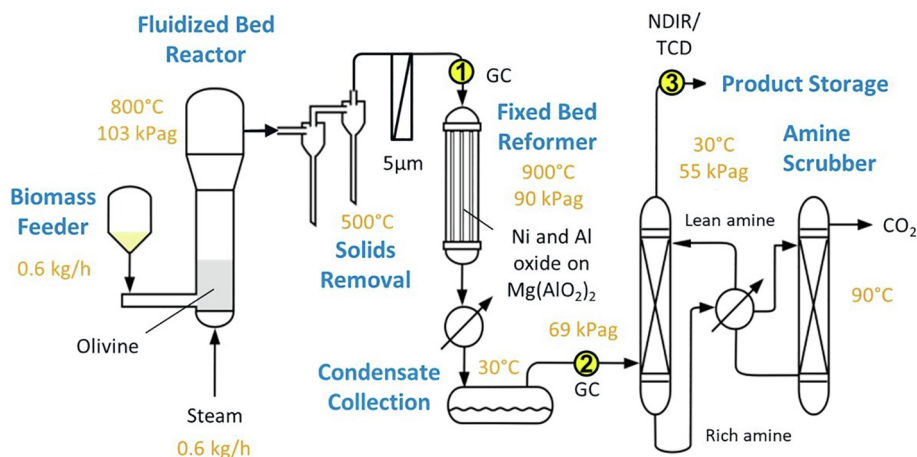


Fig. 1. Schematic of fluidized bed gasification system with downstream hydrocarbon reformer and acid-gas scrubber highlighting three analytical locations.

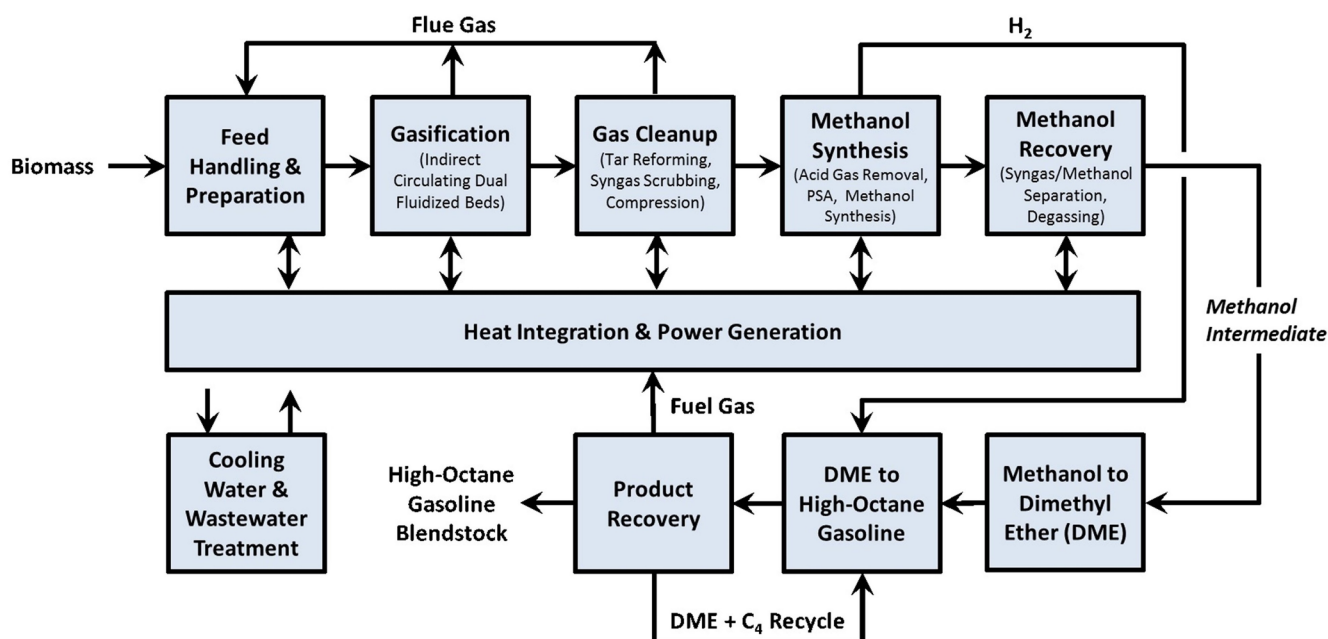


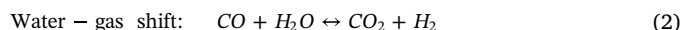
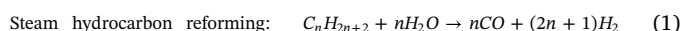
Fig. 2. Simplified block flow diagram of the biomass-to-HOG blendstock conversion process. Adapted from Tan et al. [16].

using a LECO TruSpec CHN and S add-on module, was conducted using a modified ASTM D5373-16 method (Flour and Plant Tissue Method) to accommodate biomass samples that uses a slightly different burn profile of 4 slm for 40 s, 1 slm for 30 s, and 4 slm for 30 s of ultra-high purity O₂. Elemental sulfur content was determined using ASTM D4239-17, and oxygen content was determined by difference. Higher and lower heating values (HHV, LHV) for the feedstocks were determined with a LECO AC600 Calorimeter using ASTM D5865-13.

2.3. Gasification

A schematic of the gasification system used in these experiments is shown in Fig. 1. A dual-screw K-Tron hopper metered biomass at 0.6 kg h⁻¹ to a 15.9 mm (OD) feed screw that continuously conveyed it into a 10.16 cm (ID) fluidized bed reactor maintained at 800 °C and 103 kPa. Steam was introduced through the bottom of the reactor at 0.6 kg h⁻¹ to fluidize the olivine bed material, yielding a 1:1 (wt/wt) steam to biomass ratio. A series of two downstream cyclones and a hot gas filter at 500 °C and 98 kPa removed solids from the syngas stream before reforming. The fixed bed reformer, held at 900 °C and 90 kPa,

contained 7.86 kg of a commercial nickel reforming catalyst (Haldor-Topsoe R-67-7H) which upgraded the raw product gas, contributing to an increase in syngas yield, removal of hydrocarbons (Eq. (1)), and a shift in the relative H₂ and CO concentrations (Eq. (2)).



After reforming, the syngas was cooled to approximately 30 °C and 69 kPa to condense water and any residual heavy hydrocarbons before finally passing through an acid-gas scrubber at 90 °C and 55 kPa to remove CO₂ and H₂S. The scrubbing fluid contained 30 wt% monoethanolamine (MEA), 10 wt% methyl-diethanolamine (MDEA), and 60 wt% water. The syngas composition was measured at three points within the system as depicted in Fig. 1. An Agilent 7890A gas chromatograph (GC) calibrated for permanent gases and hydrocarbon compounds up to C₄ analyzed a slip-stream of raw and reformed syngas at locations one and two, respectively. A California Analytical Instruments nondispersive infrared analyzer (NDIR) and Nova Analytical Systems thermal conductivity detector (TCD) continuously monitored

CO, CO₂, O₂, CH₄, and H₂ concentrations at the outlet of the acid-gas scrubber, location 3. The NDIR and TCD data was used to confirm steady-state operation, at which point data collection commenced. In total, gases were sampled over a minimum of three consecutive gas injections per stream at a rate of one sample every 20 min for a total of six datasets (three pre-reformer, three post-reformer).

2.4. Techno-economic analysis

A simplified process flow diagram for the biomass-to-HOG conversion pathway used as the exemplary TEA case is shown in Fig. 2. The detailed process description can be found in Tan et al. [16]. The diagram depicts the major processing steps for the conversion of biomass to syngas via indirect steam gasification, syngas cleanup, and sequential synthesis of methanol, dimethyl ether (DME), and high-octane hydrocarbons.

The primary economic indicator for this analysis is specific feedstock cost, which is defined as the cost of HOG production attributed to the feedstock cost, in dollars per gallon of gasoline equivalent (\$/GGE), as illustrated in Equation (3). GGE is based on the lower heating value (LHV) of gasoline (32,356 kJ/L) obtained from Argonne National Laboratory's GREET model software [17]; the LHV for HOG in this work is 31,094 kJ/L. All costs are adjusted to 2014 US dollars. The HOG yields as a function of feedstock compositions were determined from the Aspen Plus process model simulation [16].

$$\text{Specific Feedstock Cost} = \frac{\text{Feedstock Cost}}{\text{HOG Yield}} \quad (3)$$

The assumed design capacity was 2000 dry tonnes per day (2205 dry US tons per day). With an expected 7884 operating hours per year (90% on-stream factor/availability), the annual feedstock requirement is approximately 657,000 dry tonnes per year (724,000 dry US tons per year). The assumed on-stream factor allows approximately 36 days of planned and unplanned downtime per year.

The TEA reported here uses nth-plant economic assumptions, the key aspect of which is that a successful industry has been established with many operating plants using similar process technologies. The TEA model encompasses a process model and an economic model. For a given set of conversion parameters, the process model solves mass and energy balances for each unit operation. This data is used to size and cost process equipment and compute raw material and other operating costs. The capital and operating costs are then used for a discounted cash flow rate of return analysis [16]. The nth-plant economic assumptions are summarized in Table 1, while the capital costs and annual operating costs are presented in Tables 2 and 3, respectively.

2.5. Life-cycle assessment

A complete life-cycle assessment (LCA) study typically evaluates multiple impact categories, including global warming potential, acidification, eutrophication, resource depletion, and water use. While LCA can certainly be employed to evaluate a wide range of sustainability indicators, this study focuses only on the life-cycle GHG emissions. The scope of this attributional LCA study concentrated on the field-to-wheels (FTW) GHG emissions of the high-octane gasoline blendstock. GHG emissions are represented in grams of carbon dioxide equivalent (CO_{2e}) using a 100-year GHG emission factor [18]. The system boundary for the LCA study is depicted in Fig. 3. For this analysis, we account for the stages in the life cycle of the HOG fuel, including feedstock production and logistics, fuel production and transportation, and fuel consumption or vehicle operation. The functional unit is one megajoule (MJ) of fuel consumed. Additionally, the current LCA was performed to evaluate the entire supply chain or life-cycle GHG emissions of the high-octane gasoline product and is not intended to assess only on any particular unit operation (e.g., gasification).

The corresponding reference flows and life-cycle inventories are

Table 1
Summary of nth-plant assumptions for techno-economic analysis.

Description of Assumption	Assumed Value
Cost year	2014 US dollars
IRR on equity	10%
Plant financing by equity/debt	40%/60% of total capital investment
Plant life	30 years
Income tax rate	35%
Interest rate for debt financing	8.0% annually
Term for debt financing	10 years
Working capital cost	5.0% of fixed capital investment (excluding land purchase cost)
Depreciation schedule	7-Year MACRS schedule ^a
Construction period (spending schedule)	3 Years (8% Y1, 60% Y2, 32% Y3)
Plant salvage value	No value
Startup time	6 months
Revenue and costs during startup	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream percentage after startup	90% (7884 operating hours per year)

^a Capital depreciation is computed according to the United States Internal Revenue Service modified accelerated cost recovery system (MACRS). Because the plant described here is not a net exporter of electricity, the steam plant and power generation equipment are not depreciated over a 20-year recovery period, according to the Internal Revenue Service. The whole plant capital is depreciated over a 7-year recovery period.

summarized in Table 4, which are based on material and energy inputs and outputs to the biorefinery estimated from the simulated conversion processes. The material and energy flows in the conversion step capture the impacts of input raw materials, and outputs, such as emissions, wastes, and coproducts as predicted by the process model. The coproducts (excess electricity) are treated as avoided products using the product displacement method [19]. Coproduct displacement is also known as system boundary expansion and is based on the concept of displacing the existing product with the new product. [17]. The GHG basis values for biomass feedstock production and logistics, fuel transportation and end use, and electricity are largely applied consistently with the values utilized in GREET [17]. Table 5 summarizes the GHG emission factors employed for the LCA evaluation. The GHG emission factors are used to convert the life-cycle inventory to the life-cycle GHG emissions to a common unit (g CO_{2e}/MJ). It is assumed that carbon sequestered during biomass growth ends up in the fuel after the production step and returns to the atmosphere in the exhaust stream after the fuel combusts in the engine, so that biogenic carbon is treated as credit.

3. Results and discussion

3.1. Feedstock properties

The experimentally measured proximate, ultimate, and HHV for each of the five base feedstocks, and the calculated weighted average values for each blend are presented in Table 6.

Table 6 also includes projected delivered feedstock costs from several sources. The logistics and feedstock costs are combined into a single delivered feedstock cost and reported in consistent US 2014\$. It is important to note that the projected cost from each source varies according to assumptions behind the analyses, including volume demand, location, draw radius, required preprocessing and other factors. The assumed feedstock costs reported here were based on the BETO 2016 MYPP and reduced by \$9.90/dry tonne to remove the cost for fine grinding, which is not necessary for gasification. The range of the projected costs for each feedstock varies by approximately \$21/dry tonne (SG) to approximately \$39/dry tonne (CP). Following a previous analysis [27], we applied a sensitivity of \$30/tonne to represent

Table 2
Summary of biomass-to-HOG capital costs.

in MM\$	CP	HP	MI	SG	FR	50% FR 50% SG	60% FR 30% CP 10% HP
Feed Handling & Drying	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Gasification	47.40	47.40	47.40	47.40	47.40	47.40	47.40
Gas Cleanup	59.50	57.80	58.90	56.00	59.20	57.30	59.30
Methanol Synthesis	38.10	37.10	37.80	36.20	38.00	36.90	38.10
Methanol Conditioning	2.70	2.60	2.70	2.50	2.70	2.60	2.70
DME & Hydrocarbons Conversion	49.60	47.70	48.90	45.20	49.40	47.30	49.30
Gasoline Separations	5.10	5.00	5.10	4.70	5.10	4.90	5.10
Steam System & Power Generation	39.40	37.60	38.80	33.60	39.30	37.50	39.20
Cooling Water & Other Utilities	7.00	6.90	6.90	6.80	7.00	6.90	7.00
Total Installed Equipment Cost (TIC)	249.00	242.30	246.70	232.60	248.30	241.00	248.30
Other Direct Costs	8.10	7.90	8.00	7.70	8.10	7.90	8.10
Total Direct Costs (TDC)	257.20	250.10	254.70	240.30	256.40	248.90	256.30
Indirect Costs	154.30	150.10	152.80	144.20	153.80	149.30	153.80
Land Purchase Cost	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Working Capital	20.60	20.00	20.40	19.20	20.50	19.90	20.50
Total Capital Investment (TCI)	433.80	421.80	429.50	405.20	432.30	419.80	432.20

uncertainty in these values.

3.2. Syngas composition

To assess the performance of the gasifier and provide a baseline with which to evaluate the efficiency of the catalytic reformer, raw syngas compositions were first measured at the gasifier outlet. GC data was acquired and averaged for a minimum of three injections and provided a mass balance closure of 90–99% across the different feedstocks. Across the feedstocks and blends, the raw gasified syngas composition consisted of 35–40% H₂, 23–29% CO, 20–23% CO₂, 10–12% CH₄, and 3.5–4.1% C₂₊ hydrocarbons on a dry and inert-free basis (Table 7). HHV for the gasified syngas ranged between 61 and 67 MJ/kg and the H₂:CO ratio ranged between 1.19 and 1.75 which is, on average, ca 21.5% less than stoichiometric conditions for full conversion to methanol, the precursor to HOG synthesis [28]. In comparing the raw syngas quality between feedstocks and blends, the H₂:CO and HHV varied only slightly between feedstocks apart from MI, which by comparison showed a lower observed H₂ fraction of ca 35% compared to 39–40% in the other feedstocks. Further, 6 of the 7 feedstocks showed nearly identical syngas yields (1.09–1.15 Nm³/kg_{feed}) with the 60/30/10 blend being an outlier at 1.41 Nm³/kg_{feed}.

The reformed syngas exhibited an even tighter distribution of products, consisting of 57–58% H₂, 20–23% CO, 19–23% CO₂, < 0.4% CH₄, and < 0.01% C₂₊ hydrocarbons (Table 8). HHV ranged from 82.8 to 84.5 MJ·kg⁻¹, H₂:CO ranged from 2.47 to 2.84, and yields ranged from 2.10 to 2.35 Nm³_{gas}·kg_{feed}⁻¹ across the five base feedstocks and two blends. Notably, the hydrocarbon content of the syngas decreased from ca 15% in the raw syngas down to ca 0.4%, resulting in a hydrocarbon removal efficiency of ca 97% and a significant increase in H₂ concentration, thereby improving overall gas yield, HHV, and H₂:CO ratio which subsequently meets the 2:1 stoichiometric ratio required for MeOH synthesis. As in the case of the raw syngas, the reformed syngas

Table 3
Summary of biomass-to-HOG annual operating costs.

MM\$/yr	CP	HP	MI	SG	FR	50% FR 50% SG	60% FR 30% CP 10% HP
Feedstock	69.50	63.00	49.50	51.10	49.50	50.30	58.40
Catalysts	11.70	11.20	11.50	10.40	11.60	11.00	11.60
Olivine	0.60	0.60	0.60	0.50	0.60	0.50	0.60
Other Raw Material Costs	1.70	1.70	1.70	1.80	1.80	1.80	1.70
Waste Disposal	0.50	0.60	0.90	3.80	2.10	2.90	1.50
Electricity	0.00	0.00	0.00	1.10	0.00	0.10	0.00
Fixed Costs	20.50	20.10	20.40	19.50	20.50	20.00	20.50
Coproduct Credits	-1.23	-0.40	-0.86	0.00	-0.93	0.00	-0.94

demonstrated similar properties across the different feedstocks and blends. The previously seen H₂/CO deviations in the raw syngas from MI are no longer observed, likely a result of hydrocarbon reforming (Eq. (1)) and water-gas shift activity (Eq. (2)) in the catalytic reformer.

Although the feedstocks ranged from relatively inexpensive waste products such as forest residues (\$70.55/tonne) to more expensive and higher quality biomass such as clean loblolly pine (\$95.90/tonne), the distribution of reformed syngas compositions, heating values, and yields were similar, indicating that for these feedstocks, price and performance are not strongly correlated. Of the five unblended feedstocks tested, those with the highest and lowest reformed syngas yield and HHV were FR and SG, respectively. In examining the ultimate analysis shown in Table 6, we attribute the increased performance and observed 11% difference in yield to the ca 12% difference in the carbon content of the two feedstocks, consistent with previous studies on other carbonaceous feedstocks [29,30]. Importantly, during gasification operations, which typically lasted 3–8 h per experiment, no noticeable operational differences were observed between feedstocks (e.g., jamming, plugging, etc.).

To further examine the relationship between feedstock properties and the reformed syngas quality, proximate and ultimate analysis values listed in Table 6 were compared against reformed syngas data provided in Table 8. The observed correlations were between feedstock carbon content and reformed syngas H₂ vol%, yields, and heating values, indicating that maximizing feedstock carbon content should be a major consideration in feedstock selection for large-scale gasification and when blending feedstocks (Fig. 4). Over the 7% feedstock carbon content range studied, H₂ vol% and HHV increased by ca 2% while yield increased by ca 10%. Therefore, maximizing carbon content will mainly increase syngas yield with the additional benefit of marginally increasing H₂ vol% and HHV.

As discussed above, two blends comprising 50%FR + 50% SG and 60%FR + 30% CP + 10% HP were studied to assess blend linearity and

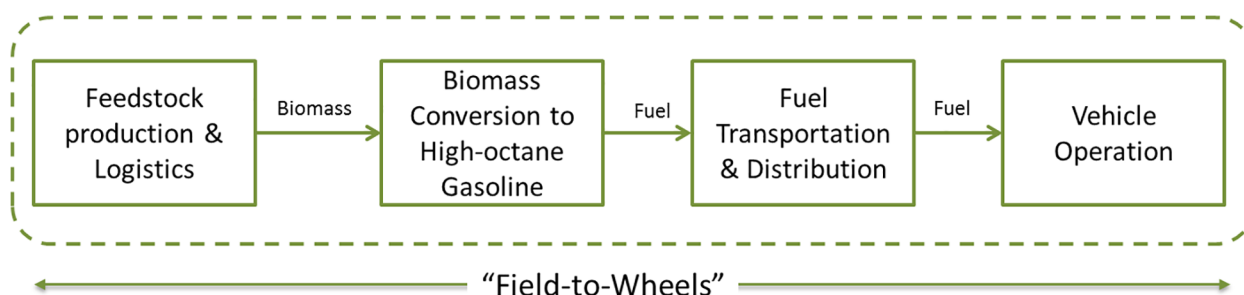


Fig. 3. Life-cycle system boundary for LCA evaluation.

Table 4

Life cycle inventory for the high-octane gasoline production with various biomass feedstocks.

Product	CP	HP	MI	SG	FR	50% FR 50% SG	60% FR 30% CP 10% HP
High-octane gasoline (HOG), MJ/hr	6.75E+05	6.43E+05	6.63E+05	5.94E+05	6.69E+05	6.32E+05	6.70E+05
<i>Co-product</i>							
Excess electricity, kWh/MJ	3.97E−03	1.35E−03	2.82E−03	−3.94E−03	3.02E−03	−2.32E−04	3.05E−03
<i>Resource Consumption, g/MJ</i>							
Biomass feedstock (dry basis)	1.23E+02	1.30E+02	1.26E+02	1.40E+02	1.24E+02	1.32E+02	1.24E+02
Magnesium oxide (MgO)	3.56E−03	4.81E−03	7.25E−03	4.40E−02	2.05E−02	3.15E−02	1.38E−02
Fresh olivine	3.66E−01	3.83E−01	3.69E−01	3.76E−01	3.52E−01	3.63E−01	3.58E−01
Tar reformer catalyst	6.56E−03	6.65E−03	6.59E−03	6.88E−03	6.56E−03	6.72E−03	6.58E−03
Methanol synthesis catalyst	3.77E−03	3.78E−03	3.78E−03	4.00E−03	3.80E−03	3.84E−03	3.80E−03
DME catalyst	4.84E−03	4.84E−03	4.84E−03	4.84E−03	4.84E−03	4.84E−03	4.84E−03
Beta zeolite catalyst	2.18E−02	2.18E−02	2.18E−02	2.18E−02	2.18E−02	2.18E−02	2.18E−02
Zinc oxide catalyst	1.66E−03	1.74E−03	1.69E−03	1.88E−03	1.67E−03	1.77E−03	1.67E−03
Cooling tower water makeup	6.55E+00	5.95E+00	6.63E+00	8.28E+00	8.08E+00	8.05E+00	7.38E+00
Boiler feed water makeup	6.68E+01	6.90E+01	6.75E+01	7.18E+01	6.73E+01	6.91E+01	6.68E+01
Dimethyl disulfide (DMDS)	1.40E−03	1.47E−03	1.42E−03	1.59E−03	1.41E−03	1.50E−03	1.41E−03
Amine (MDEA) makeup	2.77E−03	2.78E−03	2.78E−03	2.81E−03	2.77E−03	2.79E−03	2.77E−03
LO-CAT chemicals	9.48E−02	9.96E−02	9.65E−02	1.08E−01	9.57E−02	1.01E−01	9.56E−02
Boiler feed water chemicals	2.07E−03	2.02E−03	2.05E−03	2.00E−03	2.08E−03	2.04E−03	2.07E−03
Cooling tower chemicals	3.81E−04	3.83E−04	3.84E−04	4.18E−04	3.96E−04	4.05E−04	3.90E−04
No. 2 diesel fuel	4.65E−02	4.88E−02	4.73E−02	5.29E−02	4.69E−02	4.97E−02	4.68E−02
<i>Waste Streams, g/MJ</i>							
Sand and ash purge	1.33E+00	1.69E+00	2.33E+00	1.23E+01	5.91E+00	8.89E+00	4.11E+00
Tar reformer catalyst	5.96E−03	6.04E−03	5.99E−03	6.25E−03	5.96E−03	6.11E−03	5.98E−03
Scrubber solids	2.39E−03	4.46E−03	4.22E−03	1.81E−02	5.84E−03	1.04E−02	5.90E−03
Wastewater	1.15E+01	1.18E+01	1.16E+01	1.24E+01	1.15E+01	1.19E+01	1.15E+01
<i>Air Emissions, g/MJ</i>							
Carbon dioxide (CO ₂)	1.63E+02	1.64E+02	1.64E+02	1.63E+02	1.65E+02	1.64E+02	1.64E+02
Nitrogen oxides (NO ₂)	2.86E−02	5.98E−02	5.81E−02	2.56E−01	8.65E−02	1.51E−01	8.63E−02
Sulfur dioxide (SO ₂)	2.05E−02	2.15E−02	2.08E−02	4.24E−01	2.07E−02	2.19E−02	2.06E−02
Water (H ₂ O)	4.34E+01	4.75E+01	4.37E+01	4.87E+01	3.90E+01	4.37E+01	4.04E+01

possible feedstock synergies, and the results are presented in Fig. 5. The 50/50 and 60/30/10 blends exhibited a nearly linear behavior with respect to their component feedstock properties (e.g., composition, yield, H₂:CO ratio) indicating that for the selection of feedstocks studied here, blend properties can be predicted within error using weight-averaged values of the component feedstocks.

3.3. Techno-economic analysis and life-cycle assessment

Biomass feedstock compositions play a direct role on the overall yield of biofuels. The economic viability of a biomass-to-fuel conversion process depends significantly on both the feedstock cost and the biofuel yield. The production of a HOG blendstock via gasification of biomass through methanol/dimethyl ether intermediates [16] was selected for the economic feasibility assessment of the feedstocks in this study.

The data in Table 9 reveals that MI and FR have the lowest specific feedstock cost, at \$1.16/GGE and \$1.15/GGE respectively, while HP has the highest cost at \$1.68/GGE. SG, CP, and the two blended feedstocks have specific feedstock costs between \$1.24 and \$1.60/GGE. In addition to specific feedstock costs, HOG production cost contributions

from capital charges and taxes, ash removal, additional process costs, fuel production and yield were also considered. The total production cost, which encompasses the specific feedstock cost, ash removal cost, other operating costs and credits, and capital charges and taxes, ranged from \$3.36/GGE for the MI case to \$3.92/GGE for the HP case. Feedstock cost represents the biggest source of production cost. The FR and HP cases exhibit the lowest and highest specific feedstock cost contribution, 34.1% and 42.8%, respectively. Specific feedstock costs vary by up to \$0.53/GGE, while each of the other contributions vary by less than \$0.28/GGE. The comparatively high variation in specific feedstock cost indicates that when selecting a feedstock, total delivered cost is the most important economic consideration for HOG production since feedstock selection has minimal impact on downstream economics.

Fig. 6 presents the FTW GHG emissions of the biomass-to-HOG pathway for the five feedstocks and two blends. The stacked bars depict the contribution from each life-cycle stage. LCA results reveal that the life-cycle GHG emissions depend on the feedstock and the corresponding HOG yields. The life-cycle stage that contributes the most is the feedstock production and logistics (farm-to-gate). GHGs for the combined fuel transportation, distribution, and combustion for all cases

Table 5
Greenhouse gas emission factors used for LCA evaluation.

Processes/Resources	GHG Emission Factors	Units	Sources
Loblolly pine (CP)	65.65	kg CO ₂ equiv./dry tonne	This study ^a
Hybrid poplar (HP)	83.56	kg CO ₂ equiv./dry tonne	[17]
Miscanthus (MI)	87.47	kg CO ₂ equiv./dry tonne	[17]
Switchgrass (SG)	99.03	kg CO ₂ equiv./dry tonne	[17]
Forest residues (FR)	52.77	kg CO ₂ equiv./dry tonne	[17]
50% FR 50% SG	75.90	kg CO ₂ equiv./dry tonne	This study ^b
60% FR 30% CP 10% HP	59.71	kg CO ₂ equiv./dry tonne	This study ^b
Magnesium oxide (MgO)	0.63	kg CO ₂ equiv./kg	This study ^a
Fresh olivine	0.48	kg CO ₂ equiv./kg	This study ^a
Tar reformer catalyst	6.14	kg CO ₂ equiv./kg	This study ^a
Methanol synthesis catalyst	2.97	kg CO ₂ equiv./kg	This study ^a
DME catalyst	1.12	kg CO ₂ equiv./kg	This study ^a
Beta zeolite catalyst	12.80	kg CO ₂ equiv./kg	This study ^a
Zinc oxide catalyst	6.76	kg CO ₂ equiv./kg	This study ^a
Dimethyl disulfide (DMDS)	12.80	kg CO ₂ equiv./kg	This study ^a
Amine (MDEA) makeup	12.80	kg CO ₂ equiv./kg	This study ^a
LO-CAT chemicals	12.80	kg CO ₂ equiv./kg	This study ^a
Boiler feed water chemicals	12.80	kg CO ₂ equiv./kg	This study ^a
Cooling tower chemicals	12.80	kg CO ₂ equiv./kg	This study ^a
No. 2 diesel fuel	10.86	kg CO ₂ equiv./kg	This study ^a
Solid material landfill	2.65E-03	kg CO ₂ equiv./kg	[20]
Wastewater treatment	2.47	kg CO ₂ equiv./m ³	[20]
US average grid electricity	0.54	kg CO ₂ equiv./kWh	This study ^a

^a Derived or obtained from unpublished LCA studies performed in GREET.

^b GHG emission factors for the blended biomass are based on mass average of the underlying feedstocks.

Table 6
Proximate, ultimate, higher-heating values, and total assumed delivered cost (2014\$/dry tonne) for the five base feedstocks and two blends.

Feedstock	CP	HP	MI	FR ¹³	SG	50% FR 50% SG	60% FR 30% CP 10% HP
Moisture ¹³	1.15	4.00	5.61	6.85	3.62	5.24	4.86
VM ^{2,4}	83.7	86.5	85.5	74.7	76.3	75.5	78.6
Ash ^{2,5}	0.65	0.87	1.40	4.03	7.6	5.81	2.70
FC ^{2,6}	15.6	12.6	13.1	21.3	16.1	18.7	18.7
H ⁷	6.01	6.05	5.85	5.54	5.56	5.55	5.73
C ⁸	51.4	49.1	50.6	51.4	45.1	48.3	51.2
N ⁹	0.14	0.11	0.21	0.33	0.85	0.59	0.25
O ¹⁰	41.8	43.8	41.9	38.6	40.8	39.7	40.1
S ¹¹	0.02	0.01	0.01	0.04	0.09	0.07	0.03
HHV ¹²	20.99	20.34	19.75	20.66	18.21	19.44	20.73
Assumed cost ¹⁴	95.90	95.90	68.34	70.55	68.34	69.45	80.69

¹As-determined. ²Dry basis. Maximum standard deviations are as follows: ³ ± 0.13, ⁴ ± 0.3, ⁵ ± 0.05, ⁶ ± 0.4, ⁷ ± 0.04, ⁸ ± 0.3, ⁹ ± 0.03, ¹⁰ ± 0.8, ¹¹ ± 0.02, ¹²(MJ/kg) ± 0.37. ¹³Forest residues were not air-classified. ¹⁴Costs represent an estimate based on multiple recent sources [14,21–26]. Additional Note: Moisture, Volatile Matter (VM), Ash, and Fixed Carbon (FC) comprise the proximate analysis while H, C, N, O, and S comprise the Ultimate Analysis. The ultimate analyses are reported as dry basis. All costs reflect 2014\$/dry tonne.

Table 7
Steady-state measurements of raw syngas composition, yield, and higher heating values on dry and inert-free basis.

Feedstock	H ₂ ¹ (%)	CO ² (%)	CO ₂ ³ (%)	CH ₄ ⁴ (%)	C ₂₊ ⁵ (%)	H ₂ :CO	HHV (MJ·kg ⁻¹) ⁶	Yield (Nm ³ ·kg ⁻¹) ^{7,8}
CP	39.0	25.8	20.1	11.0	4.0	1.51	65.9	1.12
HP	39.5	22.8	22.8	11.2	3.7	1.73	66.12	1.09
MI	35.1	29.5	19.6	11.8	4.1	1.19	61.11	1.10
FR	38.8	25.6	20.9	10.8	4.0	1.52	65.32	1.15
SG	39.9	22.8	23.4	10.4	3.5	1.75	66.18	1.14
50% FR, 50% SG	39.5	23.2	22.7	10.9	3.9	1.70	66.06	1.10
60% FR, 30% CP, 10% HP	39.9	24.7	20.7	10.9	3.8	1.61	66.84	1.41

Maximum standard deviations are as follows: ¹ ± 0.01, ² ± 0.02, ³ ± 0.02, ⁴ ± 0.1, ⁵ ± 0.01, ⁶ ± 1.55, and ⁷ ± 0.11. ⁸ Yields calculated on a dry, ash-free basis.

are identical at 1.25 g CO_{2e}/MJ, excluding CO₂ from fuel combustion as it is biogenic CO₂ (from fuel originated from biomass). FR exhibits the lowest overall life-cycle GHGs, at 8.7 g CO_{2e}/MJ. On the other hand, SG has the highest FTW GHG emissions (24.4 g CO_{2e}/MJ), primarily because it has the lowest yield and highest farm-to-gate GHGs (13.9 g CO_{2e}/MJ). Further, excess electricity co-product credits are only associated with the conversion stage. For the cases that result in excess heat or power production, energy in the form of electricity will be exported to the grid for a co-product credit. About 30% of the carbon in the feedstock ends up as char which in turn is the key energy source for the on-site heat and power generation. Both SG and the 50/50 blend feedstocks exhibit the lowest carbon content, 45.1% and 48.3%, respectively (see Table 6). Consequently, these two cases require electricity import from the grid (no electricity credits), as shown in Fig. 6.

It is noteworthy that sensitivity analysis can play an important role in the LCA interpretation phase. However, this analysis is outside the scope of this study. Future studies will include performing sensitivity analysis on the LCA results. Specifically, since feedstock production and logistics contribute the most to the life-cycle GHG emissions, we will need to work with feedstock researchers to identify key relevant parameters that may include the yield of biomass, feedstock preprocessing energy consumption, and transportation distance. The LCA results from this study can serve as the baseline for future comparison and as a basis for comparing this process to other biomass-to-liquid fuel pathways.

Table 8

Steady-state measurements of the reformed syngas composition and calculated yield, lower, and higher heating values on an inert-free and dry basis.

Feedstock	H ₂ ¹ (vol%)	CO ² (vol%)	CO ₂ ³ (vol%)	CH ₄ ⁴ (vol%)	C ₂₊ ⁵ (vol%)	H ₂ :CO	HHV (MJ·kg ⁻¹) ⁶	Yield (Nm ³ gas·kg _{feed} ⁻¹) ^{7,8}
CP	57.7	23.4	18.5	0.38	0.01	2.47	84.52	2.29
HP	57.5	23.1	19.2	0.22	0.01	2.49	84.13	2.26
MI	57.8	21.6	20.4	0.24	0.01	2.68	84.33	2.23
FR	57.9	22.2	19.7	0.27	0.01	2.61	84.55	2.35
SG	56.7	20.0	22.9	0.33	0.01	2.84	82.77	2.10
50% FR, 50% SG	57.4	21.5	20.9	0.29	0.01	2.67	83.81	2.19
60% FR, 30% CP, 10% HP	57.7	22.9	19.0	0.37	0.01	2.52	84.50	2.26

Maximum standard deviations are as follows: ¹ ± 0.1, ² ± 0.9, ³ ± 0.9, ⁴ ± 0.1, ⁵ ± 0.01, ⁶ ± 1.55, and ⁷ ± 0.11. ⁸ Yields calculated on a dry, ash-free basis.

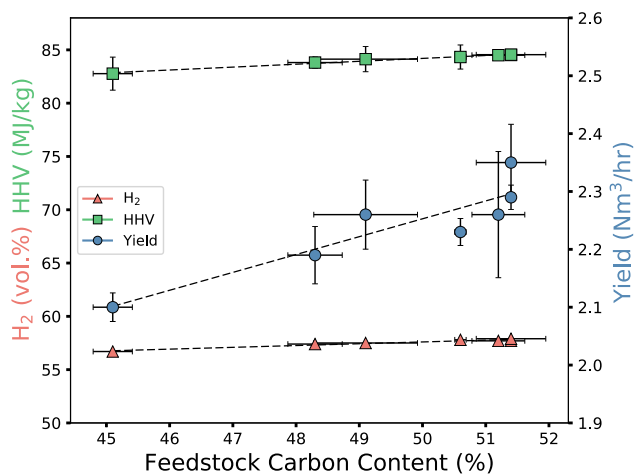


Fig. 4. H₂ content, HHV, and yield for all feedstocks as a function of feedstock carbon content.

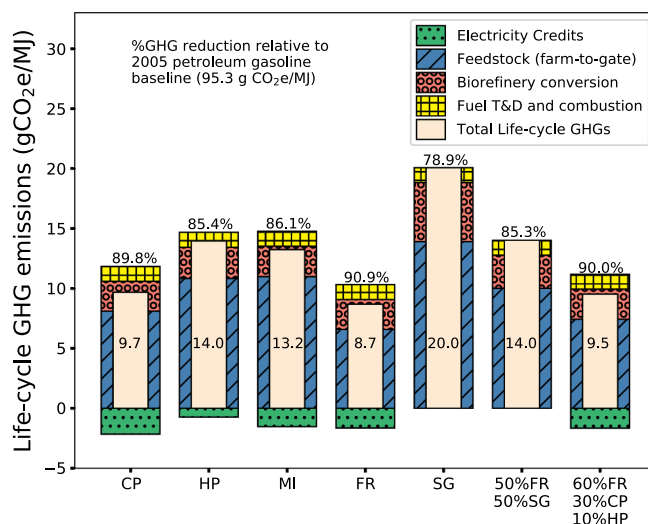


Fig. 6. Life-cycle GHG emissions for each feedstock tested.

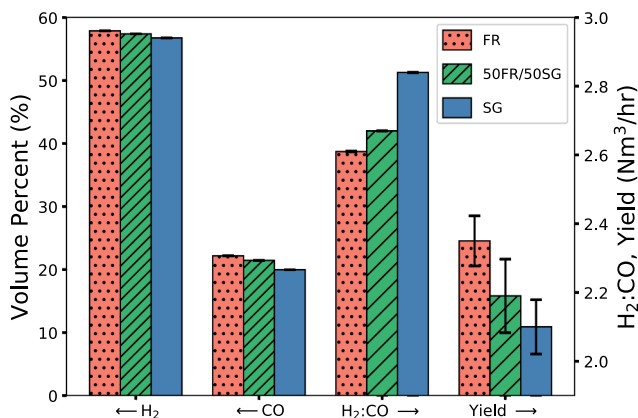


Fig. 5. Blend linearity of 50% FR + 50% SG with respect to H₂ vol%, CO%, H₂:CO, and yield.

Table 9

Techno-economic analysis cost breakdown by feedstock.

Economic Parameter	CP	HP	MI	SG	FR	50% FR 50% SG	60% FR 30% CP 10% HP
<i>Cost Contributions \$/GGE</i>							
Specific Feedstock Cost	1.60	1.68	1.16	1.34	1.15	1.24	1.35
Ash Removal	0.01	0.01	0.02	0.10	0.05	0.07	0.03
Other Operating Costs & Credits	0.56	0.60	0.58	0.67	0.57	0.62	0.57
Capital Charges & Taxes	1.60	1.63	1.61	1.69	1.60	1.64	1.60
Total Production Cost, \$/GGE	3.77	3.92	3.36	3.79	3.37	3.57	3.56
Fuel Production, MM GGE/yr	43.5	41.4	42.7	38.2	43.1	40.7	43.1
Product Yield, GGE/dry tonne	66.2	63.0	65.0	58.2	65.6	61.9	65.7

4. Conclusions

Although clean wood is often perceived as the highest quality biomass for thermochemical conversion, energy crops and waste streams are economically promising feedstocks due to their low delivered costs. Further, from a carbon management perspective, waste products possess the lowest carbon footprint due to low farm-to-gate related emissions. The challenge for industrial gasification plants then becomes making the process robust enough to handle varying feedstock inputs over time. Thoughtfully engineered biomass processing and solids feeding systems will address feedstock handling while the steam-hydrocarbon reforming of syngas offers a proven method to generate consistent composition. Developments in solids handling will enhance the versatility of biorefineries and thus enable decision makers to select feedstocks based almost exclusively on low feedstock delivery cost and low farm-to-gate emissions that will generate a high syngas yield. Thus, biorefineries become more profitable and environmentally friendly in the production of chemicals and fuels from waste- and biomass-derived syngas.

Reformed syngas compositions, heating values, and yields were similar for the feedstocks and blends studied, suggesting that biorefineries may respond to market conditions by using a broad variety of feedstocks without significant deviation in syngas quality. The reformed syngas properties from blends may be accurately predicted using a linear combination of the comprising feedstocks. For feedstock selection, carbon content and total delivered cost are the most significant considerations. Techno-economic analysis indicates that miscanthus and forest residues are the most economical feedstocks, while life-cycle assessment shows that forest residues is the most environmentally benign due to lower “farm-to-gate” and in-process CO₂ emissions.

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